# POTENTIAL IMPACTS OF THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT AIR CREDIT LIMITATIONS AND ONCE-THROUGH COOLING MITIGATION ON SOUTHERN CALIFORNIA'S ELECTRICITY SYSTEM


**Eileen Allen**
*Siting, Transmission and Environmental Protection Division*
*California Energy Commission*

**Denny Brown**
**Mike Jaske**
*Electricity Supply Analysis Division*
*California Energy Commission*

**Joe Loyer**
*Energy Efficiency & Renewables Division*
*California Energy Commission*

**Richard Ratliff**
*Legal Office*
*California Energy Commission*




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# Overview

As California's demand for electricity increases, Southern California continues to be the region most vulnerable to supply shortages. In addition to long-term contract and utility-owned generation, Southern California utilities rely on electricity purchased from aging power plants under short- and long-term contracts to maintain sufficient reserve margins and provide for local area reliability, specifically in the Los Angeles Basin. Despite significant amounts of energy efficiency and roof top solar photovoltaic systems included in the Energy Commission's demand forecasts, new or repowered natural gas generation is required in Southern California for five important reasons:

- To "firm up" the intermittency characteristics of renewable generation
- To address once-through cooling (OTC) impacts
- To replace aging plants and improve efficiency of the generating fleet
- To meet load growth after demand-side measures have been installed; and
- To satisfy overall system resource needs

New generating capacity development to replace these aging power plants is critical to achieving environmental improvements, including reduced greenhouse gas (GHG) emissions from more efficient use of natural gas and reduced impacts on coastal and marine environments by moving away from once-through-cooling for power generation. However, recent court rulings limiting the supply of air emissions credits in the South Coast Air Quality Management District (SCAQMD) present new challenges for California to achieve these important environmental improvements while at the same time ensuring sufficient generating supplies for system resource needs and local area reliability.

Southern California air basins also have some of the worst air quality in the nation, resulting in stringent local air quality requirements, including offsetting new sources of emissions with reductions in emissions from existing sources. These offsets, or emission credits, are in short supply in the SCAQMD, and constrain the ability to license new power plants or repower existing aging plants in Southern California. In 1990, the SCAQMD established a Priority Reserve of emission credits that were set aside for use by entities that serve a public interest, but did not explicitly include power generation as an industry eligible to use the credits.

In August 2007, the SCAQMD amended its Priority Reserve Rules by establishing air quality and economic criteria that allowed these offsets to be purchased for new power plants licensed by the Energy Commission. The SCAQMD, under Rule 1309.1, limited these power plant credits, requiring developers to have a one-year power sales contracts and a license from the Energy Commission to construct their facility before the SCAQMD Board would release any credits for that facility. Plants being proposed by municipal utilities were allowed only enough credits to build projects that serve their native load. The SCAQMD also limited the total amount of new electricity generating capacity that could access Priority Reserve credits to no more than 2,700 megawatts.

The SCAQMD Priority Reserve Rule was challenged in Superior Court and in July 2008, the court decision found the air district's California Environmental Quality Act (CEQA) analysis inadequate and indicated that a sufficient environmental document would require significant new analysis that the SCAQMD believes it cannot reasonably provide. As a consequence, the SCAQMD is unable to issue any offsets for power plants or for any facilities requiring a permit for emissions. The SCAQMD is now working to modify its regulations to allow permits for non-power plant facilities, but has no specific plans to develop new rules specific to power plants. A second, unresolved lawsuit in federal court is challenging whether the credits used to justify the amount of emission in the priority reserve bank have been tracked and accounted for properly. (See Attachment 2 for a complete account of these details.)

The Energy Commission, in its *2005 Integrated Energy Policy Report*, called for the retirement, replacement, and/or repowering of aging power plants. These power plants operate at high heat rates when compared with new generation technologies resulting in less efficient use of natural gas and higher levels of air pollutants, including GHG emissions. The Energy Commission also recommended that the California Public Utilities Commission (CPUC) ensure that long-term resource procurement explicitly takes into account the retiring, replacing, and/or repowering aging power plants with cleaner, combustion-based technologies that operate at higher efficiencies. This includes aging power plants in the Los Angeles Basin. In its 2006 LTPP decision, D.07-12-052, the CPUC included substantial retirements in determining future investor owned utility (IOU) needs.

Previous studies of large amounts of renewable generation technologies have shown two operating characteristics that require dispatchable generating resources to augment intermittent renewables: (1) the uncertainty of wind generation on a real time basis, requiring dispatchable generation to "ramp" up and down as wind output fluctuations, and (2) to address the systematic output variations during the year, in particular, the mismatch between annual peak loads under extreme temperatures and the expected lower generation from wind resources under such conditions. As the state's aged steam boiler power plants have become less economic, they have gradually shifted their operational patterns from baseload to less certain load following. The *2009 Integrated Energy Policy Report* will examine this issue in greater depth this year.

In addition, 13 of the state's 19 coastal power plants – which face challenges from using ocean water for cooling – are located in the southern part of the state. Once-through cooling is a technology that uses seawater to cool and re-condense superheated steam after it has been used to generate power and has significant impacts on marine organisms and ocean habitat. The federal Clean Water Act requires facilities to address these impacts, and the State Water Resources Control Board (SWRCB) is moving forward with stringent limitations on OTC facilities to implement these requirements. In its March 2008 preliminary OTC mitigation policy proposal, SWRCB suggested fossil power plants operating at less than 20 percent annual capacity factor have to mitigate OTC by converting to wet cooling towers (or the water flow equivalent). **Figure 1** shows the aging power plants using OTC (which are located within the SCAQMD jurisdiction area) the power plants that Priority Reserve credits have been requested, and the boundaries of the California Independent System Operator's (California ISO) Los Angeles Basin load pocket.

If new gas-fired power plants cannot be licensed in the Los Angeles Basin because air emission credits from the SCAQMD priority reserve are unavailable and other rules favorable to power plant development are disallowed, system reliability will require continued and ongoing operation of aging, less efficient, higher emission power plants to maintain planning reserve margins between 15-17 percent. Although the SWRCB could consider delaying the forced retirement of OTC power plants, it is unclear how long such a delay can continue and remain consistent with the U.S. Environmental Protection Agency's (U.S. EPA) enforcement of Clean Water Act provisions.

This shortage of emission credits could have a negative impact on Southern California's ability to meet the California Independent System Operator's (California ISO) summer peak and local capacity requirements as early as 2011. Local capacity requirements are designed by the California ISO to ensure that there is sufficient generation to provide uninterrupted service during all hours even if a major power plant or transmission line fails. In 2008, the Los Angeles Basin is meeting nearly half of its electrical load with local generating capacity, including aging power plants.

Currently, the planning processes for new generation and transmission projects do not address the scale and schedule of proposed likely retirements of existing OTC power plants, thus inhibiting the replacement of these power plants with new infrastructure in the Los Angeles Basin.[1] Under the current emission credit limitations, the environmental improvements that accompany investments in new and updated infrastructure are delayed and the long-term reliability of the region's electricity supplies is jeopardized.

This paper provides background and analysis of the potential impact on the overall supply/demand balance for electricity – expressed as reserve margins – for Southern California as well as local reliability concerns[2] from the SCAQMD litigation and the SWRCB effort to mitigate the environmental effects of OTC.

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[1] In late 2008, California ISO conducted an abbreviated assessment of shutdowns of a large portion of the non-nuclear OTC fleet to determine the transmission and other system operational impacts. This analysis is found at: http://www.caiso.com/208b/208b8ac831b00.pdf

[2] This quantitative analysis only addresses the Los Angeles Basin load pocket within the California ISO balancing authority (control area). Some of the same issues exist for the Los Angeles Department of Water and Power control area, but these have not yet been addressed.

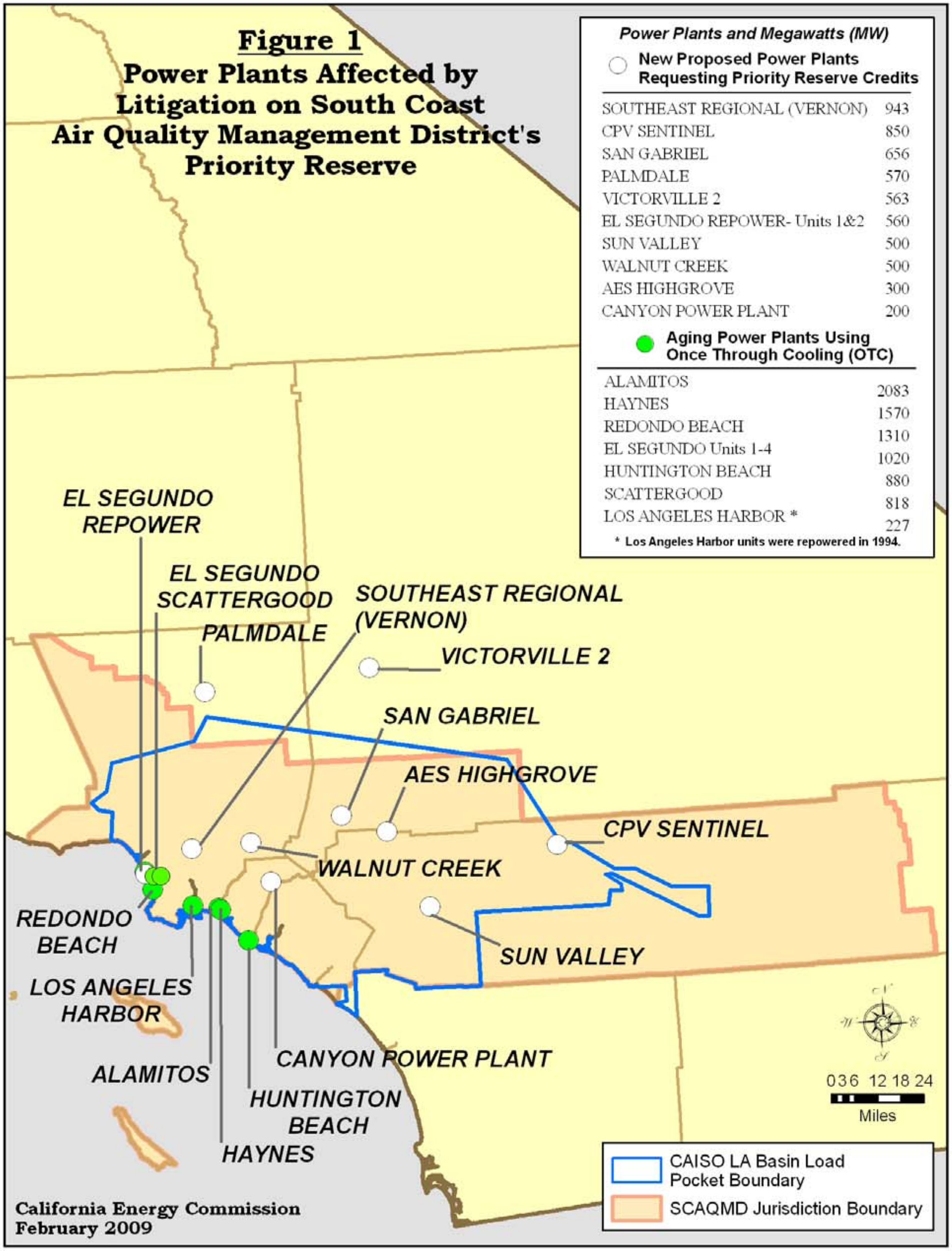

Figure 1
Power Plants Affected by Litigation on South Coast Air Quality Management District's Priority Reserve
Power Plants and Megawatts (MW)
New Proposed Power Plants Requesting Priority Reserve Credits
SOUTHEAST REGIONAL (VERNON) 943
CPV SENTINEL 850
SAN GABRIEL 656
PALMDALE 570
VICTORVILLE 2 563
EL SEGUNDO REPOWER- Units 1&2 560
SUN VALLEY 500
WALNUT CREEK 500
AES HIGHGROVE 300
CANYON POWER PLANT 200
Aging Power Plants Using Once Through Cooling (OTC)
ALAMITOS 2083
HAYNES 1570
REDONDO BEACH 1310
EL SEGUNDO Units 1-4 1020
HUNTINGTON BEACH 880
SCATTERGOOD 818
LOS ANGELES HARBOR * 227
* Los Angeles Harbor units were repowered in 1994.
EL SEGUNDO REPOWER
EL SEGUNDO
SCATTERGOOD
PALMDALE
SOUTHEAST REGIONAL (VERNON)
VICTORVILLE 2
SAN GABRIEL
AES HIGHGROVE
CPV SENTINEL
WALNUT CREEK
REDONDO BEACH
SUN VALLEY
LOS ANGELES HARBOR
CANYON POWER PLANT
ALAMITOS
HUNTINGTON BEACH
HAYNES
0 3 6 12 18 24
Miles
CAISO LA Basin Load Pocket Boundary
SCAQMD Jurisdiction Boundary
California Energy Commission
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# South Coast Air Quality Management District Court Litigation

In recent years, new power plants not relying on OTC have been proposed and licensed in the Los Angeles Basin. As directed by the federal Clean Air Act, new facilities can only be built if they can provide credits for their emissions.[3] These offsets are almost non-existent and if available, expensive to buy. Mitigation requirements for criteria pollutant emissions from new and repowered power plants in the Los Angeles Basin are governed by the SCAQMD. The SCAQMD has provided two paths for licensing these facilities, one for repowering of existing facilities, and one for new facilities. Repowering proposals are addressed by Rule 1304, which expedites licensing of existing facilities provided total capacity does not increase. For new facilities, the basic premise is that such facilities have to follow the general process for large new stationary sources and find the necessary emission reduction credits through offset markets. When offset market options have been exhausted, the only feasible source of such offsets is the SCAQMD Priority Reserve, an offset bank traditionally available only for public infrastructure, such as landfills or water treatment plants. In 2007, the SCAQMD attempted to make a portion of the Priority Reserve available for new power plant facilities by amending its rules.

The SCAQMD amended its Priority Reserve rules (Rule 1309.1) in August 2007 by establishing air quality and economic criteria allowing priority reserve credits to be purchased for new power plants that were licensed by the Energy Commission. The SCAQMD rulemaking was successfully challenged in Superior Court regarding the sufficiency of its environmental analysis. The July 2008 trial court ruling found the air district's CEQA analysis inadequate for several reasons, and indicated that an adequate CEQA document would require elaborate new analysis that the SCAQMD believes it cannot reasonably provide. As a consequence, the SCAQMD cannot issue any credits for power plants. A second ruling by the same Superior Court judge has disallowed use of Priority Reserve credits for any purpose. A second lawsuit in federal court is challenging whether the credits used to justify the amount of emissions in the Priority Reserve bank have themselves been tracked and accounted for appropriately. This suit has not yet been resolved.

The SCAQMD requires power plant proponents to perform a "due diligence" effort to purchase emission reduction credits through market mechanisms before it would consider applications for credits through its Priority Reserve. Efforts by developers to find credits on the open market, however, have been mostly unsuccessful, primarily for particulate matter ten microns or smaller (PM10). Emission reduction credits are simply not available from market sources or through other mechanisms at prices allowing new generation project development. The owners (utility and private) of offsets from previous shutdowns of older power plant units and/or from other large, stationary emission sources, such as refineries, are holding onto them to accommodate their own future growth plans.

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[3] Attachment 2 contains a fuller discussion of the SCAQMD new source review rules and emission offset requirements.

Other efforts, such as offsets from mobile sources (for example,  commercial truck fleets) have not been allowed by the U.S. EPA since there is no guarantee they would permanently provide a sufficient amount of emission reduction.

The impacts from this court ruling are that no large new stationary emission sources, such as gas-fired power plants, can be permitted in the SCAQMD region until the SCAQMD creates a rule satisfying court requirements. Such an effort is now underway, but only for those facilities for which Priority Reserve was originally designed. No comparable effort is planned for power plants at this time. Thus, the process for permitting projects in adjacent air basins using credits from the SCAQMD Priority Reserve is similarly constrained.

# State Water Resources Control Board Policy

For several years, the SWRCB and the U.S. EPA have been attempting to implement the federal Clean Water Act section 316(b) regulation governing power plant use of ocean water for OTC. The SWRCB's March 2008 preliminary policy proposal included a phased compliance time extending to 2021. Three classes of power plants would be required to reduce ocean-cooling water comparable to using a wet cooling tower, that is, ocean water could only be used for makeup of evaporative losses.[4] Fossil fuel plants with capacity factors at or below 20 percent would be required to comply by 2015, other fossil fuel plants would have to comply by 2018, and the four nuclear units (two units at each of two plants) would have to comply by 2021. A summary of two types of generating capacity affected by OTC policies, referred to as OTC capacity in this paper, which have been designated for compliance by 2015 (annual capacity factor <20 percent) and 2018 (annual capacity factor >20 percent) in the proposed OTC policy, is shown in **Table 1**.

**Table 1: OTC Fossil-Fueled Capacity in the Los Angeles Area Scheduled for Compliance in 2015 and 2018 (in Megawatts)**

| Control Area | Annual Capacity Factor < 20% (2015) | Annual Capacity Factor > 20% (2018) | Total Capacity (MW) |
|---|---|---|---|
| California ISO | 4420 | 440 | 4860 |
| LADWP | 1487 | 1154 | 2641 |
| Total | 5907 | 1594 | 7501 |

The SWRCB's proposed policy to comply with section 316(b) of the Clean Water Act would impact about one-half of the power plants in the Los Angeles Basin, translating into millions of dollars of retrofitting costs on the affected plants, and may result in some operators choosing to

[4] The SWRCB estimates this is approximately 98 percent reduction in water use.

retire the facilities rather than invest the additional capital. Alternatively, some owners have suggested they would repower if long-term contracts can be secured to allow reasonable profits. The energy agencies (Energy Commission, CPUC, and California ISO) have proposed an alternative implementation proposal to the SWRCB that links shutdown of OTC facilities to creating a replacement infrastructure, most likely a combination of new power plants, repowering of some OTC facilities, and new transmission lines reducing the need for capacity located within the Los Angeles Basin. Substantial changes to existing planning, procurement, and facility licensing processes would be required to implement this proposal. The SWRCB is considering this alternative approach.

# Likely Impact on Summer Peak Resources and Reserve Margins

Any substantial delays in the construction of new fossil fuel facilities proposed in the Los Angeles Basin will impact the electricity supplies available to meet summer peak loads. **Figure 1** shows the geographic location of the existing OTC power plants impacted and those currently in the Energy Commission licensing process affected by the SCAQMD's Priority Reserve rule (and other associated rules favorable to repowering of existing generating facilities.)

Southern California Edison (SCE) is the major utility in the Los Angeles Basin, however many municipal utilities are also located there including: Los Angeles Department of Water and Power (LADWP), Burbank Water and Power, Glendale Water and Power (all are in the LADWP control area) Anaheim, Riverside, Pasadena and other smaller municipals.

## *Impact on Municipal Utilities*

The court's SCAQMD ruling has limited impacts on Southern California municipal utilities in the California ISO control area. The City of Riverside is pursuing the 96 megawatts (MW) Riverside Energy Resource Center that requires only a limited amount of emission reduction credits through the regional offset market. In the California ISO control area, there are no permitted facilities "in reserve" that can be brought on-line without going through the Energy Commission's siting process. The rule impacts three other Southern California municipal utilities (Cities of Vernon, Anaheim, and Palmdale), but in a small way because (1) these utilities are largely resource adequate[5] (although the city of Anaheim, whose project is impacted by the ruling, will likely purchase capacity under contract for a share of their needs until the projects can be completed), (2) the total peak load for these entities grows by only 25 to 30 MW per

[5] *Progress Report on Resource Adequacy Among Publicly Owned Load-Serving Entities in California*, Staff Final Report, May 2007. CEC-200-2007-016-SF

year[6], and (3) much of this load growth is anticipated to be met with renewable resources added over the next five years to meet California's preferred resource policies. [7]

LADWP has three power plants totaling over 2,000 MW of capacity that use OTC, and apparently intends to repower most of the units in these plants. In securing air quality permits, LADWP faces the same challenges as any other entity within the SCAQMD's jurisdiction.

## *Impact on Southern California Edison*

SCE is more severely impacted by the SCAQMD ruling since the amount of capacity assumed to retire in the SCE service area over the next several years is substantial (**Table 2**.[8] ).

**Table 2: SCE Assumed Retirements**

| Year | Retirements (MW) | Cumulative (MW) |
|---|---|---|
| 2009 | 500 | |
| 2010 | 1,350 | 1,850 |
| 2011 | 1,200 | 3,050 |
| 2012 | 1,450 | 4,500 |
| 2013 | 850 | 5,350 |

These planning assumptions reflect the Energy Commission's *2005 IEPR* recommendation that the aging plants be retired (and/or repowered/replaced) by 2012 and the CPUC's direction to SCE that retirement be staggered over a longer period of time through 2018. In the following supply-demand analysis, staff is using the CPUC-approved retirement values because SCE used these values to procure new generation capacity over the five-year period.

The CPUC has authorized SCE to procure 3,200 MW of capacity to maintain service area reserve margins based on the retirement assumptions. Currently, SCE has contracted for 2,556 MW (summer peak dependable) of new generation on behalf of bundled and direct access

[6] California Energy Demand 2008-2016, Staff Revised Forecast, November 2007. CEC 200-2007-015-SF2. LADWP grows roughly at a similar amount, but Glendale, Burbank and IID are excluded from consideration in this discussion as they lie outside the California ISO control area. The figures cited in this document do not include LADWP, which is resource adequate. Per its 2007 IEPR filing, LADWP has a 2008 peak capacity requirement, including reserves of 7147 MW and has 7294 MW under its control, almost all of which (7160 MW) is utility-owned generation. LADWP's current resource plan does not indicate an intention to acquire other than renewable resources or repower existing facilities until 2013-2014, at which time it may desire to repower selected units at Haynes and Scattergood.

[7] Electricity Analysis Office publicly owned utility renewable project news tracking file.

[8] None of the capacity assumed to retire in **Table 2** is specific, such as no facilities have announced an intention to retire.

customers. The SCAQMD ruling[9] threatens 1,757 MW of this capacity that had been expected to come on-line from 2010 to 2013.

**Table 3: SCE Capacity Impacted by SCAQMD Rule**

| Year | Facility | Capacity (MW) | Cumulative (MW) |
|---|---|---|---|
| 2010 | Sentinel I | 455 | |
| 2011 | El Segundo Repower – Units 1&2 | 550 | 1,005 |
| 2012 | Sentinel II | 273 | 1,278 |
| 2013 | Walnut Creek | 479 | 1,757 |

The planning assumptions and planning reserve margin calculations for the Southern California region over the next five years using the CPUC procurement authorization assumptions are shown in **Table 4**. The Southern California portion of the California ISO control area has approximately 1,200 MW of capacity *more* than necessary to sustain a 15 percent reserve margin in 2009. Given construction of the 2,561 MW of capacity contracted for by SCE and other high probability Southern California additions that are not impacted by the SCAQMD ruling[10], *and assuming the retirement of 5,350 MW* by 2013 as described earlier, the 2013 planning reserve margin falls to about 11 percent or 1,116 MW. Clearly, this outcome would increase vulnerability to contingencies such as unusual outages.

The SCAQMD Priority Reserve ruling has a direct impact on the planning reserve margins in the Southern California area of the California ISO. When the 1,757 MW of capacity under contract to SCE and subject to the court ruling is retired in 2013, the planning reserve margin declines from the 11 percent requirement (**Table 4**) to about 5 percent (**Table 5**). This translates to a planning reserve deficit of nearly 2,900 MW in 2013 and would almost certainly lead to extensive outages, as the California ISO requires 6 percent margin for operating reserves.

[9] The nameplate capacity totals 1,910 MW in the table/legend contained in Figure 1. The lower value of 1,757 MW represents the summer peak dependable capacity used in load-resource tables and reserve margin estimation.

[10] 2009 - Inland Empire (713), 2010 - Otay Mesa (562), Blythe I (490), 2012 – Wellhead (49) & SDGE RFO (500)

**Table 4: Southern California Planning Assumptions and Planning Reserve Margins (Includes SCE, SDG&E and California ISO Participating Municipals) Five Year Outlook including SCAQMD Power Purchase Agreements Affected by Ruling**

| Resource Adequacy Planning Conventions | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| Existing Generation[1,2] | 22,583 | 22,946 | 23,303 | 22,853 | 22,325 |
| Retirements (Projected & Aging Plants)[3] | -500 | -1,350 | -1,200 | -1,450 | -850 |
| SCE RPS (Projected@20% Capacity)[4] | 150 | 200 | 200 | 100 | 150 |
| High Probability CA Additions & PPAs | 713 | 1,507 | 550 | 822 | 479 |
| Net Import | 10,100 | 10,100 | 10,100 | 10,100 | 10,100 |
| Total Net Generation (MW) | 33,046 | 33,403 | 32,953 | 32,425 | 32,204 |
| 1-in-2 Summer Temperature Demand (Average) | 29,079 | 29,557 | 30,029 | 30,498 | 30,949 |
| Demand Response (DR)[4] | 200 | 330 | 490 | 640 | 760 |
| Interruptible/Curtailable Programs | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 |
| 15% Planning Reserve Requirement | 31,814 | 32,214 | 32,573 | 32,939 | 33,320 |
| **Planning Reserve Surplus/(Deficit)** | **1,232** | **1,189** | **380** | **(514)** | **(1,116)** |
| **Planning Reserve Margin** | **19.5%** | **19.2%** | **16.3%** | **13.2%** | **11.1%** |

[1] Based on California ISO 2009 Net Qualifying Capacity values.
[2] Includes renewable capacity already online.
[3] Include SCE projected retirements and 2005 IEPR recommended retirement of aging power plants with delayed schedule approved by CPUC.
[4] Based on SCE Resource Plan.

## *Impacts Using the Energy Commission 2005 IEPR Aging Power Plant Policy*

The *2005 IEPR* policy on retiring aging power plants includes a larger amount and faster schedule than accepted by the CPUC in its 2006 long-term procurement plans (LTPP) decision. Using a retirement schedule that is consistent with the *2005 IEPR* policy recommendations for retiring aging power plants in the SCE and San Diego Gas & Electric (SDG&E) service territories, the planning reserve margin would fall to -3.5 percent when including the 1,757 MW that is threatened by the ruling and further decline to -9.5 percent without the new planned capacity. This is more than 7,000 MW short of meeting the California ISO-required 15 percent planning reserve requirement (**Figure 2**). Clearly, this outcome would not likely happen because emergency authority would be invoked to prevent one or more of the constraints implied by air quality rules on OTC mitigation.

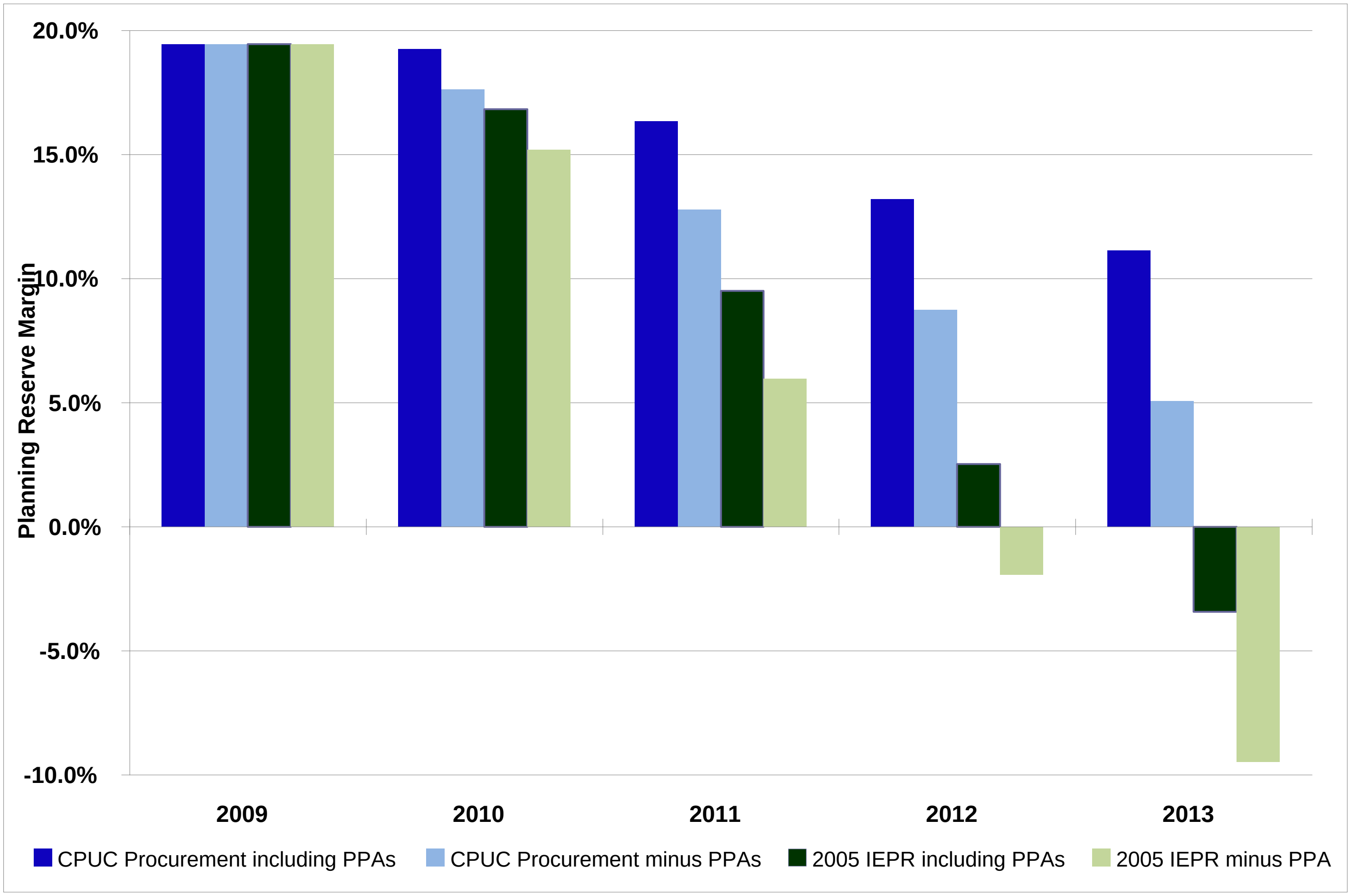
**Table 5: SCAQMD Impacts on Southern California Planning Reserve Margins (Includes SCE, SDG&E and California ISO Participating Municipals) Five Year Outlook minus SCAQMD Power Purchase Agreements Affected by Ruling**

| **Resource Adequacy Planning Conventions** | **2009** | **2010** | **2011** | **2012** | **2013** |
|---|---|---|---|---|---|
| Existing Generation[1,2] | 22,583 | 22,946 | 22,848 | 21,848 | 21,047 |
| Retirements (Projected & Aging Plants)[3] | -500 | -1,350 | -1,200 | -1,450 | -850 |
| SCE RPS (Projected@20% Capacity)[4] | 150 | 200 | 200 | 100 | 150 |
| High Probability CA Additions & PPAs | 713 | 1,052 | 0 | 549 | 0 |
| Imports carrying own reserves | 6,100 | 6,100 | 6,100 | 6,100 | 6,100 |
| Imports not carrying own reserves | 4,000 | 4,000 | 4,000 | 4,000 | 4,000 |
| Net Import | 10,100 | 10,100 | 10,100 | 10,100 | 10,100 |
| Total Net Generation (MW) | 33,046 | 32,948 | 31,948 | 31,147 | 30,447 |
| 1-in-2 Summer Temperature Demand (Average) | 29,079 | 29,557 | 30,029 | 30,498 | 30,949 |
| Demand Response (DR)[4] | 200 | 330 | 490 | 640 | 760 |
| Interruptible/Curtailable Programs | 1,215 | 1,215 | 1,215 | 1,215 | 1,215 |
| Demand Response & Interruptible Load | 1,415 | 1,545 | 1,705 | 1,855 | 1,975 |
| 15% Planning Reserve Requirement | 31,814 | 32,214 | 32,573 | 32,939 | 33,320 |
| **Planning Reserve Surplus/(Deficit)** | **1,232** | **734** | **(625)** | **(1,792)** | **(2,873)** |
| **Planning Reserve Margin** | **19.5%** | **17.6%** | **12.8%** | **8.7%** | **5.1%** |

1 Based on California ISO 2009 Net Qualifying Capacity values.
2 Includes renewable capacity already online.
3 Include SCE projected retirements and 2005 IEPR recommended retirement of aging power plants as approved by CPUC.
4 Based on SCE Resource Plan.

The net result of delaying the contracted capacity affected by the SCAQMD ruling is that reserve margins dip below acceptable planning reserve margins starting as early as 2011 and worsen through 2013 under both the CPUC procurement authorization assumptions and the *2005 IEPR* policy (**Figure 2)**. Assuming that there is no change in the air quality process, avoiding this situation may require delays in retiring an equivalent amount of aging capacity, thereby delaying efficiency gains, GHG emission reductions, and improvements to the marine environment.

**Figure 2: Comparing Impact of Ruling on Southern California Planning Reserve Margins under Alternative Retirement Assumptions**




There are five aging facilities for which retirement would most likely be deferred because of the impossibility of licensing enough replacement infrastructure by 2012 in the Los Angeles Basin local reliability area (**Table 6**)[11]. These plants are approximately one-half of the necessary local capacity in the Los Angeles Basin load pocket.

[11] *Local Capacity Requirements for 2009: Summary of Findings*, Catalin Micsa, California ISO, presented to the LCR Stakeholder meeting, March 4, 2008. Note that these values are for the California ISO and do not include LADWP capacity and needs, which includes aging plants at Haynes (1133 MW) and Scattergood (803 MW).

**Table 6: California ISO Local Capacity Requirements and Possible Delayed Retirements**

| Area/Sub-Area | LA Basin | |
|---|---|---|
| Total Capacity | 12,282 MW* | |
| LCR Capacity | 10,225 MW* | |
| Aging Plants | Alamitos 1-6 | 1,950 MW |
| | El Segundo 3-4 | 670 MW |
| | Huntington Beach 1-2 | 430 MW |
| | Redondo Beach 1-4 | 1,310 MW |
| | Etiwanda 3-4 | .640 MW |
| | Total | 5,000 MW |

# Impact on Proposed Capacity Additions in the Los Angeles Basin

The consequence of the Superior Court rulings of July and November 2008 is that currently no new stationary source in the SCAQMD region requesting access to the Priority Reserve, including large, gas-fired power plants, can be permitted. Furthermore, access to the Priority Reserve for projects in down-wind air basins, which have proposed inter-basin trades because emission reduction credits for some criteria pollutants have not been available, are not possible.

The Energy Commission has licensed over 13,000 MW of thermal power plant capacity since 2003. While a few of these projects have been abandoned, others are either under construction or awaiting financial commitments such as utility long-term contracts to begin construction.

Only three power plants licensed by the Energy Commission are located in the Los Angeles Basin load pocket and could, if developed, allow retirement of some of the existing aging power plants. These are:

- Inland Empire (maximum capacity 800 MW) secured all its required emission reduction credits, including those from the Priority Reserve. The facility operated briefly during summer 2008, however it is currently inoperable due to a turbine failure. Unit 1 is expected to be in commercial operation before summer 2009, but Unit 2 is not expected to come on line until early 2010.

- The owner of the existing El Segundo power plant, NRG Energy, secured a license for repowering of Units 1 &2 (nameplate capacity of existing units is 350 MW; license was granted for a repowered facility with nameplate capacity of 630 MW) from the Energy Commission in 2005. In June 2007, NRG petitioned to amend its license so it could build a 560 MW facility. With the current change in facility size, NRG does not have sufficient emission reduction credits to move forward with construction of its El Segundo Repower project with a nameplate capacity of 560 MW, and the district is now (according to the court ruling) unable to issue NRG any credits for the project.

- Walnut Creek Energy Center (nameplate capacity 500 MW) received a permit from the Energy Commission in summer 2008 using the SCAQMD Priority Reserve credits. The facility is currently on hold with construction to start in late 2009 pending resolution of the Priority Reserve credit issues. If these credits are invalid, then no other sources are available to allow this power plant to satisfy its permit conditions and be constructed.

There are a number of power plants currently in the licensing process at the Energy Commission that could, if permitted and brought on-line, allow more aging power plant retirement. CPV Sentinel is the most likely of these since it has a power purchase agreement with SCE, which other power plant applications in the Energy Commission licensing process do not have. Further, Sentinel is a "peaker" and would have lower levels of emissions than a baseload power plant of equal capacity. CPV filed an application with the Energy Commission in June 2007 for its Sentinel Peaker (nameplate capacity 850 MW) project, proposed in Desert Hot Springs, north of Palm Springs. This location is just within the eastern portion of the Los Angeles Basin load pocket. CPV has applied to the SCAQMD for use of Priority Reserve credits to meet its obligation to mitigate PM10 emissions; however, this issue is still unresolved.

Two other projects lie outside the Los Angeles Basin, but still are dependent on using Priority Reserve credits to go forward. The Energy Commission has licensed one and the other is in the review process.

- In July 2008, the Energy Commission licensed the Victorville 2 gas/solar hybrid project (nameplate capacity 563 MW) in the Mojave Desert Air Quality Management District, adjacent to the South Coast air basin. Victorville used an inter-basin trading approach that depended on Priority Reserve credits. If the owners are not able to find acceptable replacement credits to use in the Mojave District, they may not be able to construct and operate. The Victorville 2 project currently has no power purchase agreement.

- The Palmdale project (nameplate capacity 617 MW), currently under Energy Commission review, is also outside of the Los Angeles Basin. The Status of Projects (**Attachment 1**) provides detail on the Palmdale project, and the other projects proposed within the Los Angeles Basin, currently under Energy Commission review.

Overall, there are eight power plants currently in the Energy Commission licensing process affected by the SCAQMD Priority Reserve problem. (See **Figure 1** and **Attachment 1**.) New power plant development will be extremely limited unless the lack of available emission credits is resolved. In an environment where new power plants must be developed to replace those that will retire by the OTC rule, it is important to have sufficient lead-time to allow this replacement process to happen in a scheduled manner to assure continued reliability. With limited or no emission credits, the inability to site new or repowered generation in Southern California could delay any effective implementation of the OTC policy because of a major risk to reliability, despite the SWRCB's explicit goal to avoid such threats.[12]

## Analysis of Capacity to Satisfy Local Capacity Requirements in Los Angeles Basin Load Pocket

This section summarizes an analysis of the air quality credit/OTC mitigation conflict on local capacity requirements in the Los Angeles Basin portion of the California ISO control area. [This does not address parallel requirements of the Los Angeles Department of Water & Power control area.] The Los Angeles Basin is contained within the air shed administered by the SCAQMD. The SCAQMD's jurisdiction also extends outside the South Coast air basin to include the Palm Springs region within Riverside County (**Figure 1**).

As discussed, the Los Angeles Basin is heavily reliant on aging coastal power plants that use OTC. The SWRCB has proposed the phase-out of this cooling method, effectively requiring the closure or replacement of these Los Angeles Basin facilities. The SWRCB's proposed policy would require such extensive mitigation that most affected power plants are expected to retire rather than reinvest in control technologies necessary to meet the new requirements. With enough lead-time, however these retirements (and the electricity generated from them) could be replaced by new fossil fuel power plants that do not use OTC technologies.

The California ISO considers the Los Angeles Basin a "load pocket," defined as a local area, bounded by transmission equipment including distribution circuits, and is connected to the entire California ISO transmission grid through interconnections with limited import capacity. This means that generation internal to the load pocket must be capable of supporting load under extreme conditions to assure reliability. The California ISO determines local capacity requirements (LCR) on a year-ahead basis for each load pocket using specific criteria related to hot summer temperatures, resources in the load pocket, maximum imports, and contingency conditions.

- All load-serving entities (LSEs) in the California ISO control area are required to secure generating resources from within the load pocket based on their share of peak demand in the load pocket.[13] This process is coordinated through the resource adequacy program of the

[12] Tam Doduc, Board Chair, SWRCB. Oral comments from the May 13, 2008 public meeting to review the March 2008 OTC Policy report.

[13] The CPUC implements the California ISO LCR study in a way that allows LSEs to satisfy load pocket requirements in certain groupings rather than separately for each load pocket. Since these groupings are entirely in the inland areas of the PG&E Transmission Access Charge area, this simplification does not affect the analyses of load pockets where OTC power plants are located.

CPUC and the California ISO. LSEs are required to make these resources available to the California ISO for dispatch through contractual obligations.

A simple spreadsheet model was developed using data from prior California ISO and Energy Commission studies to evaluate whether local capacity requirements can be satisfied in future years as load grows, power plants are retired, and other power plants are added. This model does not *predict* future outcomes; however, it does allow assumptions about possible outcomes to be evaluated, focusing specifically on whether LCR values are satisfied.

Two target years, 2012 and 2015, are evaluated assuming different amounts of generation development (**Figure 3**). For 2012, the Inland Empire power plant was assumed to become operational. For 2015, two alternative assumptions about power plant development were made: (1) only the El Segundo power plant would be completed and operational, (2) the El Segundo and Walnut Creek Energy Center facilities would be constructed and in operation.

The model was run for both target years with different levels of OTC capacity retired to determine when reliability criteria in the Los Angeles Basin would no longer be satisfied. For purposes of this analysis, a surplus capacity larger than zero is considered acceptable. Having values close to zero; however, might create other market power concerns and cause capacity prices to be higher than if greater surpluses were available.

Results of the model runs, represented by the 2012 line and 2015 line (only the addition of El Segundo) on **Figure 3,** are nearly equal and can be interpreted as the addition of El Segundo is required to offset load growth between 2012 and 2015; otherwise, less OTC capacity could be retired. The alternative 2015 line (all three power plants operational) allows the greatest amount of OTC capacity to be retired without threatening local reliability.

**Figure 4** provides the results from an investigation of transmission development. In this case, only Inland Empire was assumed to be developed, which implies that the SCAQMD Priority Reserve credits never become available and the El Segundo and Walnut Creek Energy Center plants are never developed.

The California ISO has published limited information about the extent to which transmission development can reduce LCR values in the various load pockets. In the case of the Los Angeles Basin, the California ISO has indicated that four transmission projects can reduce LCR requirements.[14] Since these transmission developments take extended timeframes to develop, they are not assumed to come on-line until 2015.

The 2012 line in **Figure 4** matches that from **Figure 3** since Inland Empire is assumed to be operational. Unlike the analyses portrayed in **Figure 3**; however, in this alternative analysis of transmission upgrades, Inland remains the only power plant licensed and constructed. The initial 2015 line adds no additional generation development and no transmission line expansion. Load growth shifts this 2015 line to the left, meaning that less OTC can be retired before LCR

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[14] California ISO, Old Thermal Generation, Phase 1 Report (2008-2012 Study Results), March 2008, http://www.caiso.com/1f80/1f80a4a5568f0.pdf

capacity diminishes to threatening levels. The second 2015 line assumes that one of the four transmission lines is developed. This reduces the minimum LCR need somewhat, and allows greater OTC capacity to be retired. So the second 2015 line shifts to the right. However, even this transmission development is not enough to allow all OTC capacity to be retired. Even more transmission development would be needed to completely replace OTC capacity through a combination of new in-basin power plant capacity and new transmission.

This analysis of the local reliability consequences of various assumed power plant or transmission line developments reveals how these factors limit the amount of OTC capacity that can retire. With limited new power plant development, only about one-third of the OTC retirements of those that would likely happen if the SWRCB's proposed OTC mitigation policy were adopted as proposed in March 2008 could be allowed. System reliability would otherwise degrade below acceptable levels. Similarly, transmission line upgrades could permit some OTC-mitigation induced retirement without restoring the Priority Reserve rule. Greater power plant development (assuming restoration of Priority Reserve, or its functional equivalent) would allow greater retirements and improved OTC mitigation. It is also likely that a larger number of transmission line upgrades would also have this effect.

Finally, either the focused analysis of the Los Angeles Basin load pocket or the broader analysis of the South of Path 26 region (Path 26 is a main transmission line connecting Northern and Southern California) could identify constraints on retirement to satisfy reliability requirements. Both methods of analysis are important to full consideration of reliability and resource adequacy.

# Conclusion

The Superior Court ruling making the SCAQMD's Priority Reserve Rule invalid will constrain the amount of OTC capacity that can be retired in this area and could jeopardize local electric reliability. Assuming only a single power plant that has credits will become operational (Inland Empire), OTC retirement is limited to about 1,600 MW in 2012 and less in 2015. This is about one third of the capacity scheduled for compliance by 2015 assuming the SWRCB's March 2008 version of OTC policy is implemented without change. With development of all three power plants in the Los Angeles Basin that qualify as LCR capacity, more OTC capacity can be retired, perhaps up to 2,700 MW by 2015. With no new plants beyond Inland Empire developed, significant new transmission infrastructure is necessary to allow substantial amounts of OTC capacity to be retired.[15] Even with one of the proposed transmission projects, this only allows about 2,500 MW by 2015.

[15] This analysis only examines local capacity requirements in the Los Angeles Basin. A comparable analysis of other load pockets is needed to determine whether these have conflicts with OTC mitigation-induced retirements. However, no region of the state has such severe problems permitting new power plants, as does Southern California after the priority Reserve court decision.

Clearly, there is a conflict between OTC compliance, as scheduled by the SWRCB in their March 2008 proposed policy and the apparent inability to construct and operate new power plants as a result of the court decision overturning the SCAQMD's Priority Reserve rule[16]. To assure system reliability, some mechanism for resolving this conflict must be developed and implemented by all stakeholders and decision-makers in a timely manner.

The energy agencies (Energy Commission, CPUC, and California ISO) have developed and submitted to the SWRCB an alternative implementation proposal that respects the SWRCB's desire to significantly reduce biologic harm from OTC operations, while satisfying the societal need for a reliable electricity system. Rather than requiring OTC mitigation on a fixed schedule, the energy agencies propose that retiring existing OTC facilities be linked to the developing of replacement facilities. These facilities might be a repowered facility at an existing OTC location using a cooling technology other than OTC, a new power plant located elsewhere in Southern California, or new transmission lines within Southern California that reduce the amount of capacity required to be located within the Los Angeles Basin load pocket. The SWRCB is currently considering this proposal. If the basic approach is accepted, then more detailed development of changes to the planning, procurement and permitting processes of the three energy agencies will be needed to put this proposal into effect.

[16] The Energy Commission staff believes that SWRCB's proposed OTC mitigation will induce retirements not replacements of the water intake structures with alternative cooling systems.

**Figure 3: Surplus LCR Capacity as Function of Fossil OTC Retirements and Licensed Project Development (Los Angeles Basin Load Pocket)**

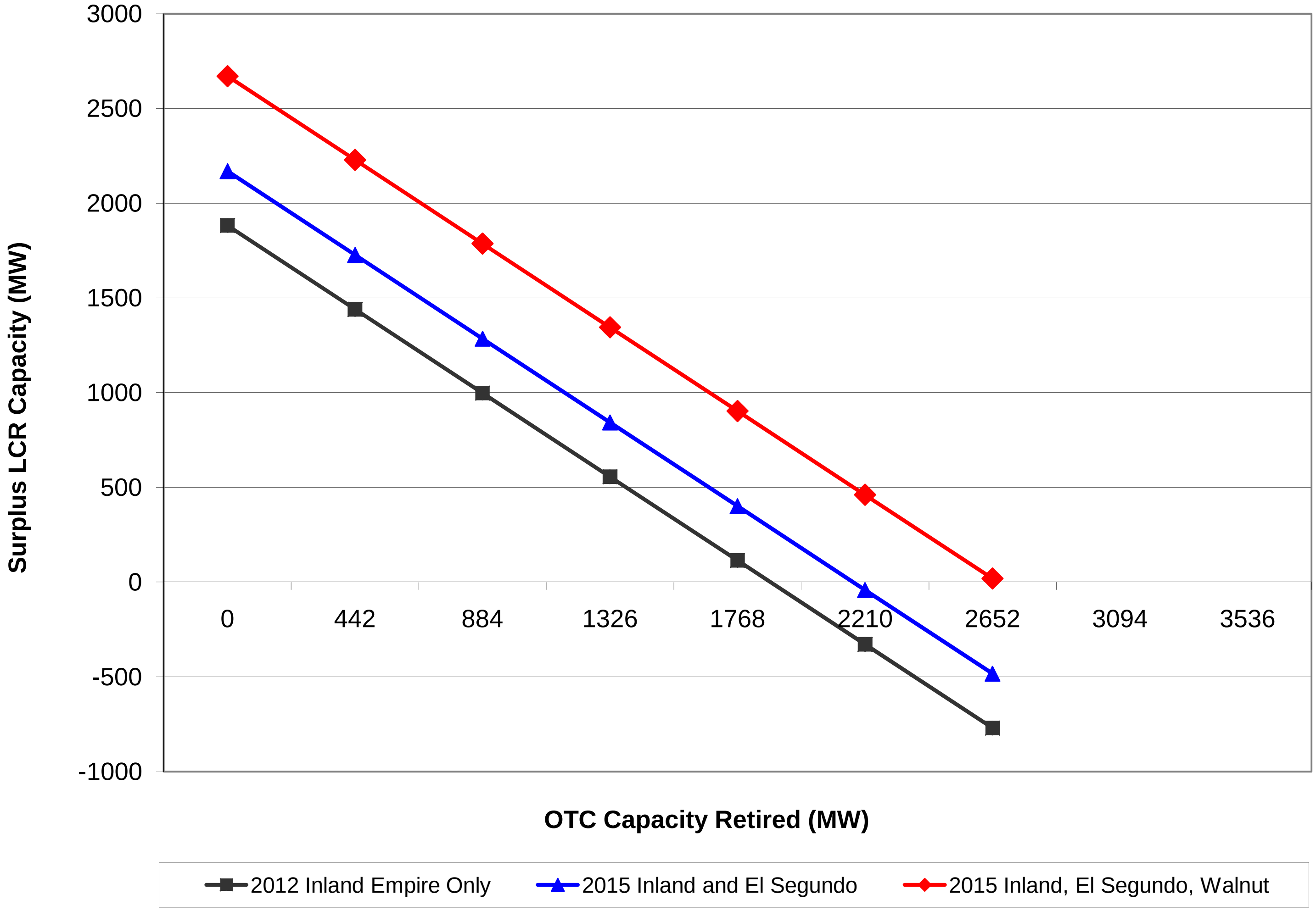
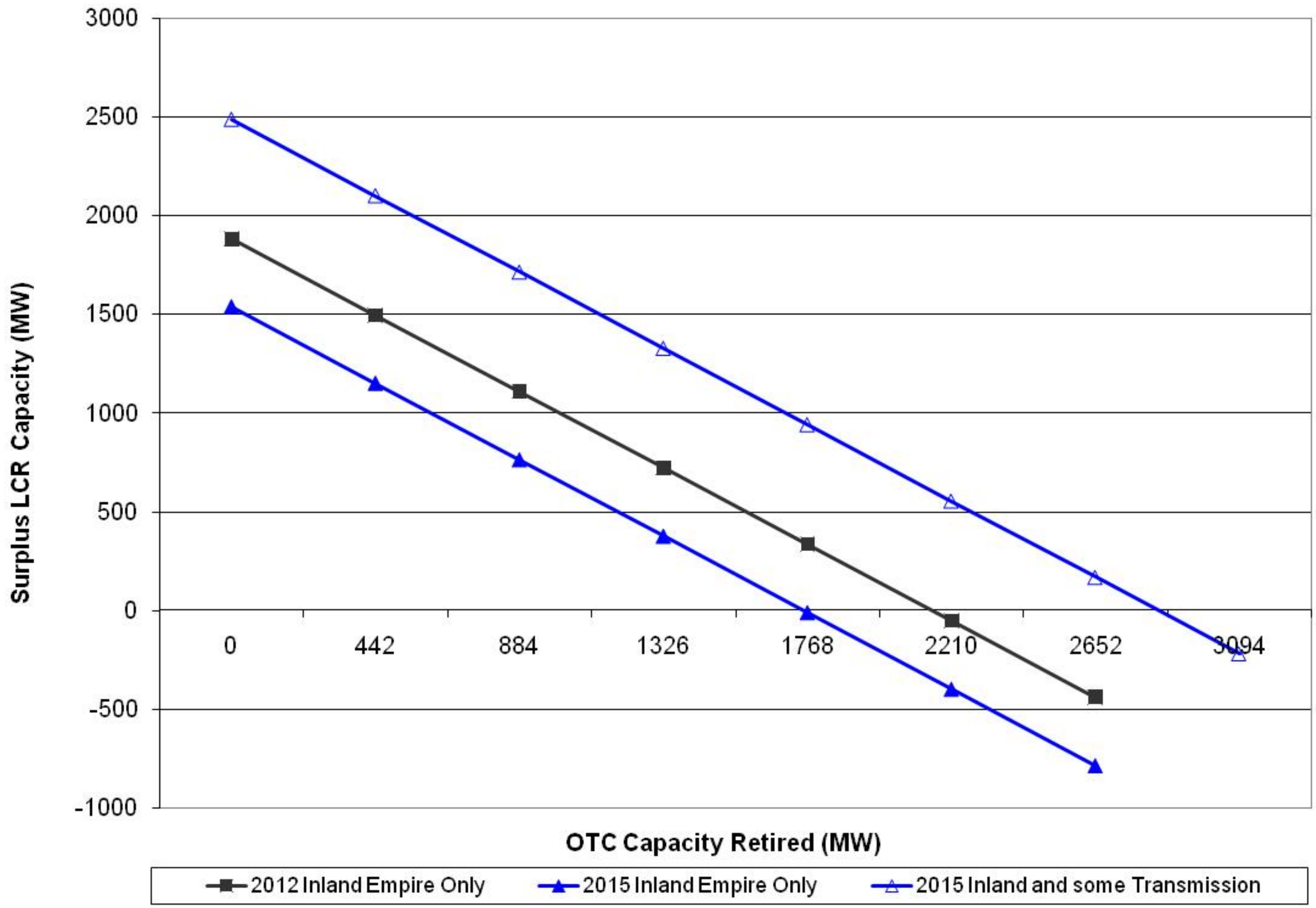


**Figure 4: Surplus LCR Capacity as a Function of OTC Retirements and Transmission Development (Los Angeles Basin Load Pocket)**



## ATTACHMENT 1: CEC-Jurisdictional Power Plants Affected by Absence of Emission Reduction Credits in SCAQMD Air Shed

| Project Name/Docket # | Staff Analysis Publication Date | MW (nominal) | Power Purchase Agreement or Muni? | Substation | Local Capacity Requirement Area |
|---|---|---|---|---|---|
| Canyon Power Plant (07-AFC-9) | PSA* date undetermined due to no PDOC* from SCAQMD | 200 | Muni | Vermont/Dowling – Yorba 69 kV (Lewis 230 kV/69kV Substation)**** | LA Basin |
| CPV Sentinel Energy Project (07-AFC-3) | 7/31/2008 | 850 | PPA w/ SCE | Devers 203 kV Substation | La Basin |
| San Gabriel Generating Station (07-AFC-2) | 3/12/08 PDOC; PSA date undetermined pending resolution of Priority Reserve issues | 656 | No | Rancho Vista Substation | LA Basin - Eastern |
| Southeast Regional Energy Center (Vernon) (06-AFC-4) | PSA date undetermined due to no PDOC from SCAQMD | 943 | Muni*** | Laguna Bell Substation | LA Basin -Western/Barre |
| AES Highgrove Project (06-AFC-2) | PSA date is undetermined due to no PDOC from SCAQMD | 300 | No | Highgrove Substation | LA/Eastern |
| Sun Valley (05-AFC-3) | FDOC received 7/14/08 FSA date undetermined pending resolution of Pr. Reserve issues | 500 | No | Valley Substation | LA Basin - Eastern |
| Walnut Creek Energy Park (05-AFC-2) | FSA 12/29/2006; licensed 2/27/08 | 500 | PPA w/ SCE | Walnut Substation | LA Basin -Western/Barre |
| El Segundo Repower (00-AFC-14C) Amendment | SA published 6/12/2008 | 560 | PPA w/ SCE | El Segundo Substation | LA Basin -Western/Barre |
| SUBTOTAL | | 4509 | | | |
| (City of) Victorville 2 Hybrid Power Project (07-AFC-1)** | FSA 11/21/2007; licensed 7/16/08 | 563 | Muni*** | Victor Substation | None |
| (City of) Palmdale Hybrid Power Plant Project (08-AFC-9) | PSA date undetermined pending PDOC and resolution of misc. issues | 570 | Muni*** | Vincent Substation | None |
| SUBTOTAL | | 1133 | | | |
| TOTAL | | 5642 | | | |

**Notes:**
*PSA – Preliminary Staff Assessment of Application For Certification (AFC) PDOC – air district's Preliminary Determination of Compliance SA – Staff Analysis (of Amendment).
FSA – Final Staff Assessment (AFC).
**Possible construction start date in late Spring 2009.
*** Capacity in excess of municipal existing load and load growth so owner will market remainder of power like merchant facility.
**** The City of Anaheim municipal transmission system interconnects with SCE/California ISO system at the Lewis 230/69 kV Substation.

# ATTACHMENT 2

# Background on South Coast Air Quality Management District Rules

## *SCAQMD New Source Review and Emission Offsets*

The SCAQMD new source review (NSR) rules require that new major sources of the criteria air pollutant emissions be offset (Rule 1303(b)(2)) at a ratio of 1.2 to 1 (that is, for one pound of pollutant emitted, 1.2 pounds must be offset). This offset is achieved by one of two methods: emission reduction credits or short-term credits (STCs).

Emission reduction credits may be created by the reduction or elimination of emissions from an existing source (Rule 1309 (a),(b)) or by allocations from the Priority Reserve (Rule 1309.1 et al). Rule 1309 (a),(b) emission reduction credits (ERCs) are the source of the "free-market" credits traded generally in the SCAQMD. The Priority Reserve credits (PRCs) have traditionally been used for essential public services (such as sewage treatment facilities) or research operations (limited to two years) and innovative technology that can lower emissions below that required by best available control technology (BACT, Rule 1303 (a)). The PRCs are supplied through the District Account, which is populated by a variety of emission reductions; most predominantly from "orphaned shutdowns" which are small (less than four tons/year) emission sources that do not apply for an emission reduction credit when they cease operation. ERCs and PRCs are the most prevalent type of offset used in the SCAQMD to date.

There are three distinct types of short-term credits (STCs) permitted in the SCAQMD rules and regulations: short-term emission reduction credits (STERCs), mobile source emission reduction credits (MSERCs) and area source emission reduction credits (ASERCs). STERCs are created from existing ERCs, which are divided, in part or in whole, for a period of no more than seven years (thereafter they become permanently divided). MSERCs are governed by SCAQMD Regulation XVI, and include sources such as the voluntary repair of on-road heavy polluting vehicles, vehicle scraping, clean vehicle programs, truck stop electrification, clean lawn and garden equipment programs and clean diesel marine vessel programs. ASERCs are governed by SCAQMD Rule 2506 (restricted to $NO_x$ and $SO_x$ credits only) and consist of the turnover of non-mobile emitting sources within the SCAQMD, which are not subject to local, or state permitting or registration. STCs must be used within the same year they were actually created (Rule 1303 (b)(2)(B)). For this reason, no power project that proposes to use STCs as the main source of offsets has been successful in attaining financial backing.

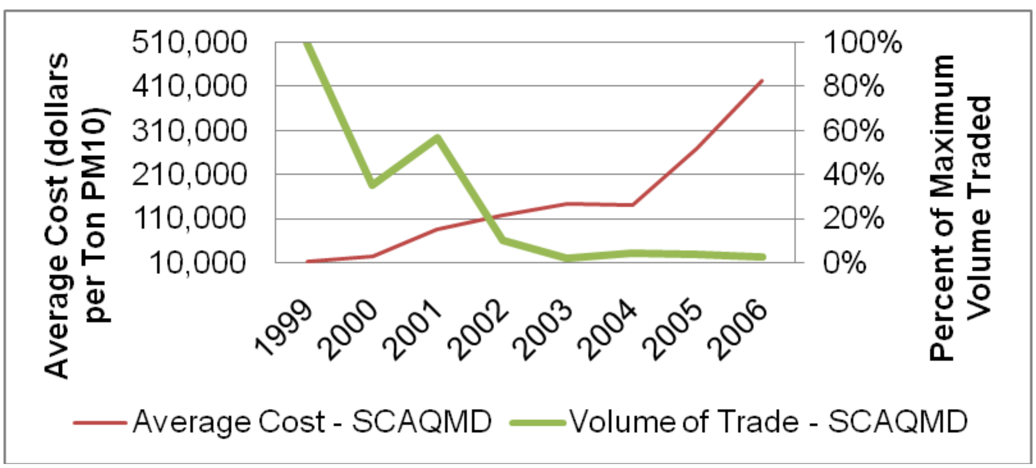
## *SCAQMD Exemptions to Offsets*

Some exemptions to the SCAQMD NSR offset requirements for all or part of the offset liability of a new or modified emission source (Rule 1304) are possible. For example, if a new or modified project emits less than four tons/year of oxides of nitrogen (NOx), oxides of sulfur (SOx), volatile organic compounds (VOC) or particulate matter less than ten microns in diameter (PM10), then the project proponent is exempted from the offset requirements of Rule 1303 (Rule 1304 (d)(2)(B)). However, the SCAQMD must offset all pollutants exempted under Rule 1304 (2007 South Coast portion of the California State Implementation Plan or SIP). The SCAQMD complies with this SIP requirement by drawing emission reduction credits from the District Account in an annual NSR Balance Report. Other exemptions in Rule 1304 generally include in-kind replacements, portable equipment, emergency equipment, facility relocation, resource recovery facilities, regulatory compliance requirements, and electric utility boiler replacements.

### *Limited PM10 Offset Availability and Priority Reserve Rule Development*

In 1998, the SCAQMD learned that the price and volume of offset market trading for PM10 ERCs were becoming unstable. The cost of PM10 ERCs increased to be prohibitively expensive which led to a shrinking number of market transactions (see **Figure 2-1**). The last major power plant project to use only PM10 ERCs was the Mountain View Power Project, a 1,000 MW natural gas-fired combustion turbine power plant approved by the Energy Commission in March 2001. Mountain View used 22 individual PM10 ERCs (5-6 are typical) plus inter-pollutant trading of SOx for PM10 (2:1 ratio) to satisfy the NSR PM10 offset requirements of 1,030 lbs/day.

**Figure 2-1: Average Annual Cost of PM10 Emission Reduction Credits South Coast Air Quality Management District1999-2006**




Source: Emission Reduction Offsets Transaction Cost Summary Reports 1999-2006, California Air Resources Board

In April 2001, the SCAQMD approved amendments, after more than a year in process, to Rule 1309.1 Priority Reserve to allow temporary access to the PRCs by qualifying Electric Generating Facilities (EGFs), including new power plant proponents. The access was granted to EGFs that performed a "good faith effort" to purchase PM10 ERCs, were deemed data complete in 2000, 2001, 2002, or 2003, and had a contract to sell at least 50 percent of their power to the California grid, among other things. Each EGF was required to show proof of their good faith efforts being made to the SCAQMD by contacting ERC holders. The SCAQMD produced periodic snapshot reports of what they termed "available credits," which meant those ERCs not secured by permits, and thus, available for sale. **Table 2-1** shows a portion of one such snapshot report for September 2008. The table only includes the PM10 ERCs for the 19 largest holders (of 74 total individual holders) and the total ERCs available in September 2008. There are enough available PM10 ERCs to permit approximately two 500 MW peaking power plants if credits from all 74 ERC holders could be purchased (not just the 19 shown). Of the 19 holders shown, the two largest are petroleum chemical based companies: BP West and Ultramar.

**Table 2-1: South Coast Air Quality Management District Summary of Active PM10 Emission Reduction Credits September 2008**

| COMPANY NAME | AVAILABLE PM10 ERCS (LBS/DAY) |
|---|---|
| BP WEST COAST PROD.LLC BP CARSON REF. | 128 |
| ULTRAMAR INC | 122 |
| LA CITY, DWP HAYNES GENERATING STATION | 31 |
| CHEVRON PRODUCTS CO. | 24 |
| UCLA | 20 |
| EQUILON ENTERPRISES, LLC | 20 |
| CONOCOPHILLIPS COMPANY | 19 |
| ULTRAMAR INC (NSR USE ONLY) | 18 |
| AERA ENERGY LLC | 18 |
| RIVERSIDE CEMENT CO (EIS USE) | 17 |
| LA CITY, DWP | 15 |
| OWENS CORNING ROOFING AND ASPHALT, LLC | 13 |
| SES TERMINAL LLC | 12 |
| CANTOR FITZGERALD BROKERAGE, LP | 12 |
| US BORAX INC | 10 |
| US GOVT, AF DEPT, MARCH AIR RESERVE BASE | 10 |
| US GOVT, NAVY DEPT LB SHIPYARD | 10 |
| BARRY CONTROLS | 10 |
| 3M COMPANY | 10 |
| **TOTAL AVAILABLE PM10 ERCs** | **808** |

Source: SCAQMD September 2008 Current Active ERC List

In 2001, qualifying EGFs could purchase PM10 PRCs for $25,000 per lbs/day, which translated into approximately $11.5 million for a 500 MW power project (approximately 460 lbs/day of PM10). The projects under the Commission jurisdiction that qualified were Inland Empire (670 MW), El Segundo (630 MW) and Malburg Generation Station (134 MW). Only Malburg was able to find and purchase at least some PM10 ERCs (approximately 6 lbs/day). Inland Empire is currently in construction, Malburg is operational, and El Segundo has been disqualified as an EGF because the applicant filed a major amendment to the project, which proposes to change the turbine manufacturer, the ultimate capacity and eliminate the once through cooling system.

The El Segundo case is unusual in that it used both the Priority Reserve (Rule 1309.1) and the Utility Boiler Exemption (Rule 1304 (a)(2)) to satisfy the SCAQMD NSR offset requirements. The 1304(a)(2) exemption was granted via the replacement of an electric generating utility boiler with combustion turbines of the same or lower capacity. However, since the El Segundo boilers (Units 1 and 2) were 340 MW total and the new combustion turbines were 630 MW, the project proponent (NRG) had to offset the additional 46 percent of their project emissions. For PM10, NRG chose to use the Priority Reserve. Since the original boilers did not produce as much PM10 as the proposed combustion turbines (about a quarter of the proposed), the SCAQMD used the emission reductions of the boiler shutdowns and emission credits from the District Account in addition to the PRCs purchase by NRG to comply with the NSR offset requirements for the project. Thus, approximately three-quarters of the offsets for the El Segundo project would have come from the District Account (via the NSR Balance of 1304 Exemptions and the PRCs purchased by NRG).

After the 2003 window had shut on the Priority Reserve, the SCAQMD found significant interest from power plant developers in re-opening it. Given the need for power development identified in the *2005 IEPR*, the SCAQMD began the process of amending Rule 1309.1, again. However, the U.S. Environmental Protection Agency (EPA) took a more active role in the process. As a result, the SCAQMD agreed to eliminate a large portion of the credits remaining in the District Account given a lack of documentation (94 percent of PM10 credits and 80 percent of all pollutant credits in total). The remaining credits were documented as real, quantifiable, permanent, and verifiable by the SCAQMD, which was accepted by the EPA.

Additionally, the EPA proposed a reporting requirement to make clear the source and disposition of all credits and debits to the District Account. The SCAQMD agreed and drafted a rule for adoption (Rule 1315). Rule 1315 also enabled the SCAQMD to replenish the District Account to some degree by allowing them to “harvest” as needed the 0.2 of the 1.2:1 offset ratio imposed by Rule 1303 on all offsets surrendered. With Rule 1315 in place and the District Account ratified by EPA, the SCAQMD proposed the second amendment to Rule 1309.1 (Priority Reserve) to allow limited use of PRCs by qualifying EGFs.

However, at this point several community groups and environmental activists had become aware of the proposed amendment and intervened in the process. The involvement of these groups forced the SCAQMD into a long public debate (approximately two years) to develop and redevelop compromises in an attempt to appease the parties involved. This finally culminated in an amendment that was ratified by the SCAQMD Governing Board in August 2007.

The 2007 amendment placed far more requirements on EGFs to qualify for access to the PRCs than in the 2001 amendment. The new amendment defined three new zones (1, 2, and 3) based on the average annual ambient PM2.5 concentration and defined an Environmental Justice Area (EJA) based on the percentage of population below the poverty level. The requirements (shown in **Table 2-1**) on an EGF to qualify became more restrictive as the number of zone facilities increased, or if they were located in an EJA. These requirements are far more restrictive than any air district has ever imposed on any class of pollution emitting devices. However, qualifying EGFs could purchase PM10 PRCs at a cost of $92,000 per lbs/day, which translates into a cost of approximately $42.32 million for a 500 MW power plant; a 370 percent increase in cost compared to the 2001 amendment. Finally, the Governing Board ordered the SCAQMD to spend the fees raised "as close as possible" to the project site.

Immediately following the Board's approval of the 2007 amendment for Rule 1309.1, the intervening community and environmental groups filed a lawsuit in the California Superior Court to enjoin the Board's action and set aside the amended rule. In July 2008, the court found for the plaintiff and suspended the amended Rule 1309.1 and Rule 1315. The court stated that the SCAQMD had failed to perform an adequate CEQA analysis to evaluate the potential impacts of all twelve power plants that proposed to make use of the PRCs under the amended rules.

Following the ruling in the state trial court, the litigants brought a separate action in federal court asking the court to find that there are no remaining ERCs in the District Account. That action is in the pre-trial stage, but the litigants contend that the District Account no longer has any credits for the purposes of complying with NSR offset requirements in the SCAQMD. They prefer to hold harmless those entities, which have used the PRCs in good faith, but rather put the burden on the SCAQMD to find (or new programs to create) new offsets.

### *Current Status*

With the remaining credits (and possibly more) in the District Account in jeopardy and the setting aside of Rule 1315; the SCAQMD might not be able to comply with the SIP requirement to produce an NSR Balance Report and thus offset any new emission sources using Rule 1304 Exemptions or Rule 1309.1 Priority Reserve. Therefore, on January 9, 2009, the SCAQMD issued a moratorium on the issuance of all new Permits to Construct or Operate that relied on the District Account to satisfy NSR requirements. This affects any facilities qualifying under the current 1309.1 (landfills, sewage treatment plants, hospitals, etc) as well as any facilities qualifying under Rule 1304 (auto body shops, dry cleaners, printers, gas stations, small power plants, etc). The SCAQMD has appealed the state court decision setting aside Rules 1309.1 and 1315, and has launched a rulemaking to re-instate Rules 1309.1 and 1315, but without the power plant access provision in Rule 1309.1. The district believes that restoring the ability to issue permits to the non-power plant facilities qualifying for these rules as essential to the economic activity of the Los Angeles region. The rulemaking is expected to take nine to twelve months.

Assuming this SCAQMD course of action is successful, sometime in 2010 there will be two options for power plant applicants: (1) qualify for an exemption under Rule 1304 and hope that needed air quality credits can be obtained from the District Account, or (2) procure ERCs on the open market. Access to Rule 1304 is limited to existing power plants qualifying for the repowering exemption, and therefore is not available to new "greenfield" power plants. Until Rule 1315 is restored, allowing access to Rule 1304 in conjunction with valid credits in the District Account, the only option for power plants is securing ERCs on the open market for whatever price they can negotiate, thus avoiding the District Account all together. The SCAQMD estimates the current price as $148,000 per pound/day; therefore, for a 500 MW peaking power plant (approximately 460 lbs/day of PM10) implies approximately 70 million dollars of additional capital investment added to the direct cost of the plant itself.[17] These prices correspond to an extreme shortage of available ERCs. The owners of these ERCs may have no interest in selling such ERCs if they have their own internal industrial facility expansion plans.

[17] Mohsen Nazemi, Deputy Executive Officer of SCAQMD, personal communication, Feb. 10, 2009.

**Table 2-2: Qualification Requirements for Electricity Generating Facilities Under Rule 1309.1 Priority Reserve, 2007 Amendment**

| Performance Requirements | Zone 1 | Zone 2 or <=500MW and in either Zone 3 or EJA | >500MW and in either Zone 3 or EJA |
|---|---|---|---|
| Cancer Risk | 10 in 1,000,000 | 1 in 1,000,000 | 0.5 in 1,000,000 |
| Non-Cancer Risk | 1 | 0.5 | 0.1 |
| Cancer Burden | 0.5 | 0.1 | 0.05 |
| Rate of PM10 Emissions | NA | <= 0.06 lbs/MW-hr | <= 0.035 lbs/MW-hr |
| Rate of $NO_x$ Emissions | NA | <= 0.08 lbs/MW-hr | <= 0.05 lbs/MW-hr |
| Total Combined PM10 Hourly Emissions | NA | NA | <= 30 lbs/hr |
| 24-hour Impact of PM10 Emissions from New or Modified EGFs | <= 2.5 ug/m$^3$ per gas turbine | <= 5 ug/m$^3$ for total combined gas turbines | <= 2.5 ug/m$^3$ for total combined gas turbines |
| Annual Impact of PM10 Emissions from New or Modified EGFs | <= 1.0 ug/m$^3$ per gas turbine | <= 0.75 ug/m$^3$ for total combined gas turbines | <= 0.5 ug/m$^3$ for total combined gas turbines |
| Yearly Maximum Hours of Operation – simple cycle only Yearly Maximum Hours of Operation – simple cycle only | NA | 4,000 hours or less | 3,000 hours or less |
| Required of all projects in all zones | Long-term contract (1 year) with the State of California to sell at least 50% of the power generated. | | |
| | Demonstrate that renewable energy is not a viable option at the proposed site (up to 10% of proposed capacity). | | |